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APPLICATION FOR UNITED STATES LETTERS PATENT

FOR

DOWNHOLE ACTIVATABLE ANNULAR SEAL ASSEMBLY

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CROSS-REFERENCE TO RELATED APPLICATIONS

[0001] This application is a continuation-in-part to U.S. Patent Application serial number 10/251,138 filed on September 20, 2002 and entitled "Active Controlled Bottomhole Pressure System and Method."

BACKGROUND OF THE INVENTION

Field of the Invention

[0002] This invention relates generally to oilfield wellbore drilling systems and more particularly to drilling systems that utilize active control of bottomhole pressure or equivalent circulating density during drilling of the wellbores. In particular aspects, the invention relates to devices and methods for establishing an effective annular seal across an active pressure differential (APD) device.

Background of the Related Art

[0003] Oilfield wellbores are drilled by rotating a drill bit conveyed into the wellbore by a drill string. The drill string includes a drill pipe (tubing) that has at its bottom end a drilling assembly (also referred to as the "bottomhole assembly" or "BHA") that carries the drill bit for drilling the wellbore. The drill pipe is made of jointed pipes. Alternatively, coiled tubing may be utilized to carry the drilling of assembly. The drilling assembly usually includes a drilling motor or a "mud motor" that rotates the drill bit. The drilling assembly also includes a variety of sensors for taking measurements of a variety of drilling, formation and BHA parameters. A suitable drilling fluid (commonly referred to as the "mud") is supplied or pumped under pressure from a source at the surface down the tubing. The drilling fluid drives the mud motor and then discharges at the bottom of the drill bit. The drilling fluid returns uphole via the annulus between the drill string and the wellbore inside and carries with it pieces of formation (commonly referred to as the "cuttings") cut or produced by the drill bit in drilling the wellbore.

[0004] For drilling wellbores under water (referred to in the industry as "offshore" or "subsea" drilling) tubing is provided at a work station

(located on a vessel or platform). One or more tubing injectors or rigs are used to move the tubing into and out of the wellbore. In riser-type drilling, a riser, which is formed by joining sections of casing or pipe, is deployed between the drilling vessel and the wellhead equipment at the sea bottom and is utilized to guide the tubing to the wellhead. The riser also serves as a conduit for fluid returning from the wellhead to the sea surface.

[0005] During drilling, the drilling operator attempts to carefully control the fluid density at the surface so as to control pressure in the wellbore, including the bottomhole pressure. Typically, the operator maintains the hydrostatic pressure of the drilling fluid in the wellbore above the formation or pore pressure to avoid well blow-out. The density of the drilling fluid and the fluid flow rate largely determines the effectiveness of the drilling fluid to carry the cuttings to the surface. One important downhole parameter controlled during drilling is the bottomhole pressure, which in turn controls the equivalent circulating density ("ECD") of the fluid at the wellbore bottom.

[0006] This term, ECD, describes the condition that exists when the drilling mud in the well is circulated. The friction pressure caused by the fluid circulating through the open hole and the casing(s) on its way back to the surface, causes an increase in the pressure profile along this path that is different from the pressure profile when the well is in a static condition (i.e., not circulating). In addition to the increase in pressure while circulating, there is an additional increase in pressure while drilling due to the introduction of drill solids into the fluid. This negative effect of the increase in pressure along the annulus of the well is an increase of the pressure which can fracture the formation at the shoe of the last casing. This can reduce the amount of hole that can be drilled before having to set an additional casing. In addition, the rate of circulation that can be achieved is also limited. Also, due to this circulating pressure increase, the ability to clean the hole is

severely restricted. This condition is exacerbated when drilling an offshore well. In offshore wells, the difference between the fracture pressures in the shallow sections of the well and the pore pressures of the deeper sections is considerably smaller compared to on shore wellbores. This is due to the seawater gradient versus the gradient that would exist if there were soil overburden for the same depth.

[0007] In some drilling applications, it is desired to drill the wellbore at at-balance condition or at under-balanced condition. The term at-balance means that the pressure in the wellbore is maintained at or near the formation pressure. The under-balanced condition means that the wellbore pressure is below the formation pressure. These two conditions are desirable because the drilling fluid under such conditions does not penetrate into the formation, thereby leaving the formation virgin for performing formation evaluation tests and measurements. In order to be able to drill a well to a total wellbore depth at the bottomhole, ECD must be reduced or controlled. In subsea wells, one approach is to use a mud- filled riser to form a subsea fluid circulation system utilizing the tubing, BHA, the annulus between the tubing and the wellbore and the mud filled riser, and then inject gas (or some other low density liquid) in the primary drilling fluid (typically in the annulus adjacent the BHA) to reduce the density of fluid downstream (i.e., in the remainder of the fluid circulation system). This so-called "dual density" approach is often referred to as drilling with compressible fluids.

[0008] Another method for changing the density gradient in a deepwater return fluid path has been proposed, but not used in practical application. This approach proposes to use a tank, such as an elastic bag, at the sea floor for receiving return fluid from the wellbore annulus and holding it at the hydrostatic pressure of the water at the sea floor. Independent of the flow in the annulus, a separate return line connected to the sea floor storage tank and a subsea lifting

pump delivers the return fluid to the surface. Although this technique (which is referred to as "dual gradient" drilling) would use a single fluid, it would also require a discontinuity in the hydraulic gradient line between the sea floor storage tank and the subsea lifting pump. This requires close monitoring and control of the pressure at the subsea storage tank, subsea hydrostatic water pressure, subsea lifting pump operation and the surface pump delivering drilling fluids under pressure into the tubing for flow downhole. The level of complexity of the required subsea instrumentation and controls as well as the difficulty of deployment of the system has delayed (if not altogether prevented) the practical application of the "dual gradient" system.

[0009] Another approach is described in U.S. Patent Application No. 09/353,275, filed on July 14, 1999 and assigned to the assignee of the present application. The U.S. Patent Application No. 09/353,275 is incorporated herein by reference in its entirety. One embodiment of this application describes a riserless system wherein a centrifugal pump in a separate return line controls the fluid flow to the surface and thus the equivalent circulating density.

[0010] U.S. Patent application no. 10/251,138, which is owned by the assignee of the present invention, and incorporated herein by reference, describes another system for ECD control. In this system, the bottomhole pressure and hence the equivalent circulating density is controlled by creating a pressure differential at a selected location in the return fluid path with an active pressure differential (APD) device to reduce or control the bottomhole pressure. This system is relatively easy to incorporate in new and existing systems. Such drilling systems typically include a rig that moves an umbilical (e.g., drill string) into and out of the wellbore. A bottomhole assembly, carrying the drill bit, is attached to the bottom end of the drill string. A well control assembly or equipment on the well receives the bottomhole assembly and the tubing. A drilling fluid system supplies a drilling fluid into the tubing,

which discharges at the drill bit and returns to the well control equipment carrying the drill cuttings via the annulus between the drill string and the wellbore. A riser dispersed between the wellhead equipment and the surface guides the drill string and provides a conduit for moving the returning fluid to the surface.

[0011] An active pressure differential (APD) device moves in the wellbore as the drill string is moved. Alternatively, the active differential pressure device is attached to the wellbore inside or wall and remains stationary relative to the wellbore during drilling. The device is operated during drilling, *i.e.*, when the drilling fluid is circulating through the wellbore, to create a pressure differential across the device. This pressure differential alters the pressure on the wellbore below or downhole of the device. The device may be controlled to reduce the bottomhole pressure by a certain amount, to maintain the bottomhole pressure at a certain value, or within a certain range. By severing or restricting the flow through the device, the bottomhole pressure may be increased.

[0012] The system also includes downhole devices for performing a variety of functions. Exemplary downhole devices include devices that control the drilling flow rate and flow paths. For example, the system can include one or more flow-control devices that can stop the flow of the fluid in the drill string and/or the annulus. Such flow-control devices can be configured to direct fluid in drill string into the annulus and/or bypass return fluid around the APD device. Another exemplary downhole device can be configured for processing the cuttings (*e.g.*, reduction of cutting size) and other debris flowing in the annulus. For example, a comminution device can be disposed in the annulus upstream of the APD device.

[0013] Sensors communicate with a controller via a telemetry system to maintain the wellbore pressure at a zone of interest at a selected

pressure or range of pressures. The sensors are strategically positioned throughout the system to provide information or data relating to one or more selected parameters of interest such as drilling parameters, drilling assembly or BHA parameters, and formation or formation evaluation parameters. The controller for suitable for drilling operations preferably includes programs for maintaining the wellbore pressure at zone at under-balance condition, at at-balance condition or at over-balanced condition. The controller may be programmed to activate downhole devices according to programmed instructions or upon the occurrence of a particular condition.

[0014] Exemplary configurations for the APD Device and associated drive includes a moineau-type pump coupled to positive displacement motor/drive via a shaft assembly. Another exemplary configuration includes a turbine drive coupled to a centrifugal-type pump via a shaft assembly. Preferably, a high-pressure seal separates a supply fluid flowing through the motor from a return fluid flowing through the pump. In a preferred embodiment, the seal is configured to bear either or both of radial and axial (thrust) forces.

[0015] In still other configurations, a positive displacement motor can drive an intermediate device such as a hydraulic motor, which drives the APD Device. Alternatively, a jet pump can be used, which can eliminate the need for a drive/motor. Moreover, pumps incorporating one or more pistons, such as hammer pumps, may also be suitable for certain applications. In still other configurations, the APD Device can be driven by an electric motor. The electric motor can be positioned external to a drill string or formed integral with a drill string. In a preferred arrangement, varying the speed of the electrical motor directly controls the speed of the rotor in the APD device, and thus the pressure differential across the APD Device.

[0016] Bypass devices are provided to allow fluid circulation in the wellbore during tripping of the system, to control the operating set points of the APD Device and/or associated drive/motor, and to provide a discharge mechanism to relieve fluid pressure. For examples, the bypass devices can selectively channel fluid around the motor/drive and the APD Device and selectively discharge drilling fluid from the drill string into the annulus. In one arrangement, the bypass device for the pump can also function as a particle bypass line for the APD device. Alternatively, a separate particle bypass can be used in addition to the pump bypass for such a function.

[0017] In order for the APD to function properly, a fluid seal must be established and maintained between the APD and the inner wall of the borehole and the outer surface of the pump. This seal is intended to be maintained during drilling. Therefore, an acceptable annular seal arrangement must perform several functions. First, the seal assembly must properly seal against the cased wellbore wall while the drill string is rotating and/or moving axially within the wellbore. Second, the seal assembly should move axially along the wellbore wall without significant damage resulting to the seal. Third, the seal should allow mud to bypass the seal while tripping.

[0018] There are difficulties with conventional seal solutions for this type of problem. A conventional rubber sealing on the outer surface of the tool, for example, or a brush seal would be prone to excessive erosion damage since the seal would have to slide along the inner surface of the casing and the casing couplings until the APD device is moved to its target depth. The risk of significantly damaging this type of seal during tripping is very high.

SUMMARY OF THE INVENTION

[0019] The present invention provides devices and methods for establishing an effective annular seal about between an APD and a surrounding wellbore sidewall. In other aspects, the invention provides a means of selectively activating such a seal during drilling operations or other operations wherein drilling mud is flowed through the drill string and returns through the annulus.

[0020] An annular seal assembly is described that creates a fluid seal between an APD and a wellbore sidewall during drilling operations. In a currently preferred embodiment, the annular seal assembly includes an inflatable packer element and a hydraulic inflation system. The hydraulic inflation system uses the fluid pressure provided by drilling mud that is returning to the surface via the annulus to inflate the packer element and set the seal. The hydraulic inflation system also buffers and regulates the fluid pressure setting the packer element to avoid overinflation of the element. Because drilling mud fluid pressure actuates the seal assembly, the seal is automatically set during drilling operations and unset when drilling ceases, thereby allowing the pump assembly to be easily relocated or removed from the wellbore following a drilling operation. The use of an inflatable packer element also ensures that the fluid seal provided by the seal assembly is somewhat flexible and resilient and, therefore, able to be moved upwardly and downwardly within the wellbore during drilling and to permit the passage by the pump housing of drilling mud returning to the surface via the annulus. In other embodiments, the seal assembly may comprise a set of mud cups that are set against the borehole sidewall using a pressure differential across the seal assembly or a spring-biased seal element.

[0021] Examples of the more important features of the invention have been summarized (albeit rather broadly) in order that the detailed description thereof that follows may be better understood and in order that the contributions they represent to the art may be appreciated. There are, of course, additional features of the invention that will be described hereinafter and which will form the subject of the claims appended hereto.

BRIEF DESCRIPTION OF THE DRAWINGS

[0022] For detailed understanding of the present invention, reference should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawing:

[0023] **Figure 1** is a schematic illustration of one embodiment of a system using an active pressure differential device to manage pressure in a predetermined wellbore location;

[0024] **Figure 2** graphically illustrates the effect of an operating active pressure differential device upon the pressure at a predetermined wellbore location;

[0025] **Figures 3A-D** are schematic illustrations of one embodiment of an arrangement according to the present invention wherein a positive displacement motor is coupled to a positive displacement pump (the APD Device);

[0026] **Figure 4** is a side, cross-sectional view of an exemplary annular seal assembly constructed in accordance with the present invention wherein the seal assembly is in an unset position.

[0027] **Figur 5** is a side, cross-sectional view of the exemplary annular seal assembly shown in Figure 7 with the seal assembly in a set position.

[0028] **Figure 6** is a schematic depiction of the hydraulic inflation system used in the exemplary annular seal assembly shown in **Figures 4** and **5**.

[0029] **Figure 7** is a side, cross-sectional view of an alternative embodiment for an annular seal assembly.

[0030] **Figure 8** is a side, cross-sectional view of a further alternative embodiment for an annular seal assembly that incorporates a set of mud cups around the outer circumference and a trip valve.

[0031] **Figure 9** is a side, cross-sectional view of another alternative embodiment for an annular seal assembly that incorporates a set of mud cups and a string valve.

[0032] **Figure 10** is a side, external view of the annular seal assembly shown in **Figure 9**.

[0033] **Figures 11** and **12** are side, cross-sectional views of a further alternative embodiment for an annular seal assembly that incorporates a sliding sleeve actuation assembly.

DETAILED DESCRIPTION OF PREFERRED EMBODIMENTS

[0034] Referring initially to **Figure 1**, there is schematically illustrated a system for performing one or more operations related to the construction, logging, completion or work-over of a hydrocarbon producing well. In particular, **Figure 1** shows a schematic elevation view of one embodiment of a wellbore drilling system **100** for drilling wellbore **90** using conventional drilling fluid circulation. The drilling system **100** is a rig for land wells and includes a drilling platform **101**, which may be a drill ship or another suitable surface workstation such as a floating platform or a semi-submersible for offshore wells. For offshore operations, additional known equipment such as a riser and

subsea wellhead will typically be used. To drill a wellbore **90**, well control equipment **125** (also referred to as the wellhead equipment) is placed above the wellbore **90**. The wellhead equipment **125** includes a blow-out-preventer stack **126** and a lubricator (not shown) with its associated flow control.

[0035] This system **100** further includes a well tool such as a drilling assembly or a bottomhole assembly ("BHA") **135** at the bottom of a suitable umbilical such as drill string or tubing **121** (such terms will be used interchangeably). In a preferred embodiment, the BHA **135** includes a drill bit **130** adapted to disintegrate rock and earth. The bit can be rotated by a surface rotary drive or a motor using pressurized fluid (e.g., mud motor) or an electrically driven motor. The tubing **121** can be formed partially or fully of drill pipe, metal or composite coiled tubing, liner, casing or other known members. Additionally, the tubing **121** can include data and power transmission carriers such fluid conduits, fiber optics, and metal conductors. Conventionally, the tubing **121** is placed at the drilling platform **101**. To drill the wellbore **90**, the BHA **135** is conveyed from the drilling platform **101** to the wellhead equipment **125** and then inserted into the wellbore **90**. The tubing **121** is moved into and out of the wellbore **90** by a suitable tubing injection system.

[0036] During drilling, a drilling fluid from a surface mud system **22** is pumped under pressure down the tubing **121** (a "supply fluid"). The mud system **22** includes a mud pit or supply source **26** and one or more pumps **28**. In one embodiment, the supply fluid operates a mud motor in the BHA **135**, which in turn rotates the drill bit **130**. The drill string **121** rotation can also be used to rotate the drill bit **130**, either in conjunction with or separately from the mud motor. The drill bit **130** disintegrates the formation (rock) into cuttings **147**. The drilling fluid leaving the drill bit travels uphole through the annulus **194** between the

drill string **121** and the wellbore wall or inside **196,** carrying the drill cuttings **147** therewith (a "return fluid"). The return fluid discharges into a separator (not shown) that separates the cuttings **147** and other solids from the return fluid and discharges the clean fluid back into the mud pit **26.** As shown in **Figure 1**, the clean mud is pumped through the tubing **121** while the mud with cuttings **147** returns to the surface via the annulus **194** up to the wellhead equipment **125.**

[0037] Once the well **90** has been drilled to a certain depth, casing **129** with a casing shoe **151** at the bottom is installed. The drilling is then continued to drill the well to a desired depth that will include one or more production sections, such as section **155**. The section below the casing shoe **151** may not be cased until it is desired to complete the well, which leaves the bottom section of the well as an open hole, as shown by numeral **156**.

[0038] As noted above, the present invention provides a drilling system for controlling bottomhole pressure at a zone of interest designated by the numeral **155** and thereby the ECD effect on the wellbore. In one embodiment of the present invention, to manage or control the pressure at the zone **155**, an active pressure differential device ("APD Device") **170** is fluidly coupled to return fluid downstream of the zone of interest **155**. The APD device is a device that is capable of creating a pressure differential "ΔP" across the device. This controlled pressure drop reduces the pressure upstream of the APD Device **170** and particularly in zone **155**.

[0039] The system **100** also includes downhole devices that separately or cooperatively perform one or more functions such as controlling the flow rate of the drilling fluid and controlling the flow paths of the drilling fluid. For example, the system **100** can include one or more flow-control devices that can stop the flow of the fluid in

the drill string and/or the annulus **194**. **Figure 1** shows an exemplary flow-control device **173** that includes a device **174** that can block the fluid flow within the drill string **121** and a device **175** that blocks can block fluid flow through the annulus **194**. The device **173** can be activated when a particular condition occurs to insulate the well above and below the flow-control device **173**. For example, the flow-control device **173** may be activated to block fluid flow communication when drilling fluid circulation is stopped so as to isolate the sections above and below the device **173**, thereby maintaining the wellbore below the device **173** at or substantially at the pressure condition prior to the stopping of the fluid circulation.

[0040] The flow-control devices **174, 175** can also be configured to selectively control the flow path of the drilling fluid. For example, the flow-control device **174** in the drill pipe **121** can be configured to direct some or all of the fluid in drill string **121** into the annulus **194**. Moreover, one or both of the flow-control devices **174, 175** can be configured to bypass some or all of the return fluid around the APD device **170**. Such an arrangement may be useful, for instance, to assist in lifting cuttings to the surface. The flow-control device **173** may include check-valves, packers and any other suitable device. Such devices may automatically activate upon the occurrence of a particular event or condition.

[0041] The system **100** also includes downhole devices for processing the cuttings (*e.g.*, reduction of cutting size) and other debris flowing in the annulus **194**. For example, a comminution device **176** can be disposed in the annulus **194** upstream of the APD device **170** to reduce the size of entrained cutting and other debris. The comminution device **176** can use known members such as blades, teeth, or rollers to crush, pulverize or otherwise disintegrate cuttings and debris entrained in the fluid flowing in the annulus **194**. The

comminution device **176** can be operated by an electric motor, a hydraulic motor, by rotation of drill string or other suitable means. The comminution device **176** can also be integrated into the APD device **170**. For instance, if a multi-stage turbine is used as the APD device **170,** then the stages adjacent the inlet to the turbine can be replaced with blades adapted to cut or shear particles before they pass through the blades of the remaining turbine stages.

[0042] Sensors $\mathbf{S_{1\text{-}n}}$ are strategically positioned throughout the system **100** to provide information or data relating to one or more selected parameters of interest (pressure, flow rate, temperature). In a preferred embodiment, the downhole devices and sensors $\mathbf{S_{1\text{-}n}}$ communicate with a controller **180** via a telemetry system (not shown). Using data provided by the sensors $\mathbf{S_{1\text{-}n}}$, the controller **180** maintains the wellbore pressure at zone **155** at a selected pressure or range of pressures. The controller **180** maintains the selected pressure by controlling the APD device **170** (e.g., adjusting amount of energy added to the return fluid line) and/or the downhole devices (e.g., adjusting flow rate through a restriction such as a valve).

[0043] When configured for drilling operations, the sensors $\mathbf{S_{1\text{-}n}}$ provide measurements relating to a variety of drilling parameters, such as fluid pressure, fluid flow rate, rotational speed of pumps and like devices, temperature, weight-on bit, rate of penetration, etc., drilling assembly or BHA parameters, such as vibration, stick slip, RPM, inclination, direction, BHA location, etc. and formation or formation evaluation parameters commonly referred to as measurement-while-drilling parameters such as resistivity, acoustic, nuclear, NMR, etc. One preferred type of sensor is a pressure sensor for measuring pressure at one or more locations. Referring still to **Fig. 1A**, pressure sensor $\mathbf{P_1}$ provides pressure data in the BHA, sensor $\mathbf{P_2}$ provides pressure data in the annulus, pressure sensor $\mathbf{P_3}$ in the supply fluid,

and pressure sensor P_4 provides pressure data at the surface. Other pressure sensors may be used to provide pressure data at any other desired place in the system **100**. Additionally, the system **100** includes fluid flow sensors such as sensor **V** that provides measurement of fluid flow at one or more places in the system.

[0044] Further, the status and condition of equipment as well as parameters relating to ambient conditions (e.g., pressure and other parameters listed above) in the system **100** can be monitored by sensors positioned throughout the system **100**: exemplary locations including at the surface (**S1**), at the APD device **170** (**S2**), at the wellhead equipment **125** (**S3**), in the supply fluid (**S4**), along the tubing **121** (**S5**), at the well tool **135** (**S6**), in the return fluid upstream of the APD device **170** (**S7**), and in the return fluid downstream of the APD device **170** (**S8**). It should be understood that other locations may also be used for the sensors $S_{1\text{-}n}$.

[0045] The controller **180** for suitable for drilling operations preferably includes programs for maintaining the wellbore pressure at zone **155** at under-balance condition, at at-balance condition or at over-balanced condition. The controller **180** includes one or more processors that process signals from the various sensors in the drilling assembly and also controls their operation. The data provided by these sensors $S_{1\text{-}n}$ and control signals transmitted by the controller **180** to control downhole devices such as devices **173-176** are communicated by a suitable two-way telemetry system (not shown). A separate processor may be used for each sensor or device. Each sensor may also have additional circuitry for its unique operations. The controller **180**, which may be either downhole or at the surface, is used herein in the generic sense for simplicity and ease of understanding and not as a limitation because the use and operation of such controllers is known in the art. The controller **180** preferably contains

one or more microprocessors or micro-controllers for processing signals and data and for performing control functions, solid state memory units for storing programmed instructions, models (which may be interactive models) and data, and other necessary control circuits. The microprocessors control the operations of the various sensors, provide communication among the downhole sensors and provide two-way data and signal communication between the drilling assembly **30**, downhole devices such as devices **173-175** and the surface equipment via the two-way telemetry. In other embodiments, the controller **180** can be a hydro-mechanical device that incorporates known mechanisms (valves, biased members, linkages cooperating to actuate tools under, for example, preset conditions).

[0046] For convenience, a single controller **180** is shown. It should be understood, however, that a plurality of controllers **180** can also be used. For example, a downhole controller can be used to collect, process and transmit data to a surface controller, which further processes the data and transmits appropriate control signals downhole. Other variations for dividing data processing tasks and generating control signals can also be used.

[0047] In general, however, during operation, the controller **180** receives the information regarding a parameter of interest and adjusts one or more downhole devices and/or APD device **170** to provide the desired pressure or range or pressure in the vicinity of the zone of interest **155**. For example, the controller **180** can receive pressure information from one or more of the sensors **(S_1-S_n)** in the system **100**. The controller **180** may control the APD Device **170** in response to one or more of: pressure, fluid flow, a formation characteristic, a wellbore characteristic and a fluid characteristic, a surface measured parameter or a parameter measured in the drill string. The controller **180** determines the ECD and adjusts the energy input to the APD device **170** to maintain the ECD at a desired or predetermined value or within

a desired or predetermined range. The wellbore system **100** thus provides a closed loop system for controlling the ECD in response to one or more parameters of interest during drilling of a wellbore. This system is relatively simple and efficient and can be incorporated into new or existing drilling systems and readily adapted to support other well construction, completion, and work-over activities.

[0048] In the embodiment shown in **Figure 1**, the APD Device **170** is shown as a turbine attached to the drill string **121** that operates within the annulus **194**. Other embodiments, described in further detail below can include centrifugal pumps, positive displacement pump, jet pumps and other like devices. During drilling, the APD Device **170** moves in the wellbore **90** along with the drill string **121**. The return fluid can flow through the APD Device **170** whether or not the turbine is operating. However, the APD Device **170**, when operated creates a differential pressure thereacross.

[0049] As described above, the system **100** in one embodiment includes a controller **180** that includes a memory and peripherals **184** for controlling the operation of the APD Device **170**, the devices **173-176**, and/or the bottomhole assembly **135**. In **Figure 1**, the controller **180** is shown placed at the surface. It, however, may be located adjacent the APD Device **170**, in the BHA **135** or at any other suitable location. The controller **180** controls the APD Device to create a desired amount of ΔP across the device, which alters the bottomhole pressure accordingly. Alternatively, the controller **180** may be programmed to activate the flow-control device **173** (or other downhole devices) according to programmed instructions or upon the occurrence of a particular condition. Thus, the controller **180** can control the APD Device in response to sensor data regarding a parameter of interest, according to programmed instructions provided to said APD Device, or in response to instructions provided to said APD Device from a remote

location. The controller **180** can, thus, operate autonomously or interactively.

[0050] During drilling, the controller **180** controls the operation of the APD Device to create a certain pressure differential across the device so as to alter the pressure on the formation or the bottomhole pressure. The controller **180** may be programmed to maintain the wellbore pressure at a value or range of values that provide an under-balance condition, an at-balance condition or an over-balanced condition. In one embodiment, the differential pressure may be altered by altering the speed of the APD Device. For instance, the bottomhole pressure may be maintained at a preselected value or within a selected range relative to a parameter of interest such as the formation pressure. The controller **180** may receive signals from one or more sensors in the system **100** and in response thereto control the operation of the APD Device to create the desired pressure differential. The controller **180** may contain pre-programmed instructions and autonomously control the APD Device or respond to signals received from another device that may be remotely located from the APD Device.

[0051] **Figure 2** graphically illustrates the ECD control provided by the above-described embodiment of the present invention and references **Figure 1** for convenience. **Figure 1** shows the APD device **170** at a depth **D1** and a representative location in the wellbore in the vicinity of the well tool **30** at a lower depth **D2**. **Figure 2** provides a depth versus pressure graph having a first curve **C1** representative of a pressure gradient before operation of the system **100** and a second curve **C2** representative of a pressure gradients during operation of the system **100**. Curve **C3** represents a theoretical curve wherein the ECD condition is not present; *i.e.*, when the well is static and not circulating and is free of drill cuttings. It will be seen that a target or

selected pressure at depth **D2** under curve **C3** cannot be met with curve **C1**. Advantageously, the system **100** reduces the hydrostatic pressure at depth **D1** and thus shifts the pressure gradient as shown by curve **C3**, which can provide the desired predetermined pressure at depth **D2**. In most instances, this shift is roughly the pressure drop provided by the APD device **170**.

[0052] Referring now to **Figures 3A-D**, there is schematically illustrated one arrangement wherein a positive displacement motor/drive **200** is coupled to a moineau-type pump **220** via a shaft assembly **240**. The motor **200** is connected to an upper string section **260** through which drilling fluid is pumped from a surface location. The pump **220** is connected to a lower drill string section **262** on which the bottomhole assembly (not shown) is attached at an end thereof. The motor **200** includes a rotor **202** and a stator **204.** Similarly, the pump **220** includes a rotor **222** and a stator **224**. The design of moineau-type pumps and motors are known to one skilled in the art and will not be discussed in further detail.

[0053] Additionally, an annular seal assembly **299** is disposed around the APD device to direct the return fluid to flow into the pump **220** (or more generally, the APD device) and to allow a pressure differential across the pump **220**. The seal **299** is an expandable packer type element that expands/contracts upon receiving a command signal to substantially prevent the return fluid from flowing between the pump **220** (or more generally, the APD device) and the casing **c** or wellbore wall. Construction and operation of exemplary constructions for the annular seal assembly **299** is described in detail below, with respect to **FIGS. 4, 5, 6, 7, 8, 9, 10, 11** and **12**.

[0054] The annular seal assembly **299**, depicted in **Figur 3D** is better understood with reference to **FIGS. 4, 5,** and **6**, as well as the

alternative embodiments depicted in **FIGS. 7-12.** The annular seal assembly **299** includes a hydraulically inflatable annular packer element **600** and a hydraulic inflation system, shown generally at **602**, that selectively inflates the element **600** for contact with the casing **c**. As noted previously, the annular seal assembly **299** radially surrounds the pump casing **225** of the APD device **170**, and more specifically, the pump **220**. Preferably, the packer element **600** is made of elastomer and is conveniently integrated directly into the outer casing or housing **225** of the pump **220**. The inflatable packer element **600** is an elastomeric element that resides within an annular groove **604** and defines a fluid channel **606** therewithin. The fluid channel **606** is in hydraulic fluid communication with the hydraulic inflation system **602**.

[0055] The hydraulic inflation system **602** is essentially a buffered system that uses fluid pressure from the flow of drilling mud to inflate the packer element **600**. In a currently preferred embodiment, the hydraulic inflation system **602** includes a pair of cylinders **608** and **610** that are disposed in a side-by-side manner and interconnect to form a cavity **612** at their upper end. The cavity **612** is in communication with the fluid channel **606** of the inflatable element **600**. The first cylinder **608** has a lower end **614** that is open to fluid pressure from drilling mud returning to the surface of the wellbore via return flow path **292**. It is noted that, in the embodiment depicted in **Figures 7** and **8**, the open lower end **614** is located on the radial exterior of the pump **220**. The first cylinder **608** also houses a compressible spring **616** and a first piston member **618**. The second cylinder **610** houses a second piston member **620** therewithin. There is also a compressible spring **622** defined within the second cylinder **610**. It is preferred that the second spring **622** provides a greater compression force than the first spring **616**. The compressible springs **616**, **622** may comprise mechanical springs or compressible fluid springs.

[0056] A hydraulic fluid chamber, shown generally at **624**, is defined within the upper portions of the first and second cylinders **608**, **610** between the first and second piston members **618** and **620**. The hydraulic fluid chamber **624** also includes the cavity **612** as well as the fluid channel **606** within the inflatable element **600**. The hydraulic fluid chamber **624** is filled with clean hydraulic fluid. **Figure 9** provides a schematic illustration of the hydraulic inflation system **602** of the annular seal assembly **299** to help better illustrate its operation.

[0057] The annular seal assembly **299** is actuated to inflate the packer element **600** during flowing of drilling mud, such as during drilling, and return of the drilling mud to the surface of the well. Drilling mud enters the open, lower end **614** of the first cylinder **608**, thereby exerting fluid pressure against the lower side of the first piston **618** and urging it upwardly within the first cylinder **608**. Upward movement of the first piston **618** will urge hydraulic fluid within the hydraulic fluid chamber **624** into the fluid channel **606** of the packer element **600**, causing the element **600** to inflate. Because fluid pressure from drilling mud flow is typically very high, the hydraulic inflation system **602** provides buffering so that the packer element **600** is not overinflated to failure. The second spring **622** and the second piston member **620** provide buffering. Excessive fluid pressure exerted upon the first piston member **618** by the drilling mud will be absorbed by compression of the second spring **622**.

[0058] The annular seal assembly **299** provides a selectively actuatable fluid seal and one that is also somewhat resilient and flexible so that the pump **220** may be moved axially upward and downward within the casing **c** during drilling operations. Certain features of the annular seal assembly **299** provide for reduced friction forces between the packer element **600** and the casing **c** of the wellbore to facilitate axial movement of the pump **220** within. First, the

amount of radial expansion of the packer element **600** is small, as compared to that of conventional inflatable packer elements that are used to separate zones within a wellbore and the like in a relatively permanent or semi permanent manner. As a result, the contact area between the packer element **600** and the casing **c** is minimized. Additionally, a lubricant, such as TEFLON®, may be used to coat the outer contacting portion of the inflatable element **600** to reduce frictional forces. Additionally, the fluid seal should be able to yield to permit drilling mud returning to the surface via the annulus to bypass the pump **220**.

[0059] In an alternative embodiment depicted in **Figure 7**, the packer element **600** of seal assembly **299'** is selectively inflated using pressure within, rather than outside of the drill pipe. In this embodiment, the open end **614A** of the first cylinder **608** is exposed to the radial interior of the pump **220**. As a result, drilling mud entering the drill string to drive the rotor **222** within the stator **224** is used to inflate the packer element **600**.

[0060] **Figure 8** shows an alternative annular seal arrangement **650** that can provide the annular seal assembly **299** for the APD device **170**. The seal arrangement **650** includes a cylindrical housing **652** having an upper connecting end **654** that will, during use, be oriented uphole and a lower connecting end **656** that are used to operably interconnect the housing **652** within the drill string **121** so that the pump inlet is hydraulically separated from the pump outlet. A radially enlarged central portion **658** of the housing **652** is defined between the two axial ends **654**, **656**. An axial mud passage **660** is centrally defined along the length of the housing **652**, and a pair of branch passages **662** extends within an upper part of the central portion to interconnect the central mud passage **660** with the radial exterior of the housing **652**.

[0061] The radially enlarged central portion **658** of the housing **652** carries thereupon a plurality (three shown) radially deformable seals in the form of mud cups **668**. The mud cups **668** annularly surround the central portion **658** and are affixed thereto, as indicated schematically by attachment portions **664**. The mud cups **668** are each shaped to form a flap that is fastened at a lower end to a sleeve stabilizer **670** and extend outwardly and upwardly from the sleeve stabilizer **670** to terminate in a contacting portion **672**. In currently preferred embodiments, the mud cups **668** are fashioned of a metal ring member **674** that is encapsulated by a flap portion **676** that is fashioned from a plastic or elastomeric material. The flap portion **676** of the mud cups **668** has a shape memory with an outward bias that enables the contacting portion **672** of each mud cup **668** to be expanded radially outwardly into contact with the casing **c**. The flap portion **676** of each of the mud cups **668** curves upwardly to form a concavity **678** within which fluid may be retained. The securing members **666** prevent movement of the sleeve **664** with respect to the housing **652**. Additionally, the securing members **666** may be removed in order to replace the sleeve **664** with an alternative sleeve having larger or smaller mud cups **668** in order to accommodate different sizes of wellbores. A trip valve **680** is disposed through the wall of the housing **652**. The trip valve **680** is a check valve that permits one-way flow of fluids from the exterior of the housing **652** into the axial mud passage **660**. It is noted that the trip valve **680** is located axially below the mud cups **668**, and the branch passages **662** are located axially above the mud cups **668**.

[0062] In operation, the seal arrangement **650** is a static seal that is intended to be set permanently within the casing **c** of the wellbore. When the seal arrangement **650** is run into the wellbore, the contacting portions **672** of the mud cups **668** are in contact with the casing **c** and

move along it. As the seal arrangement **650** is run into the wellbore, fluids within the wellbore that are below the seal arrangement **650** are displaced and may flow through the trip valve **680** into the axial mud passage **660** and then through the branch passages **662** out into the annulus. In this manner, wellbore fluids are able to bypass the seal arrangement **650** as it is run into the wellbore or when it is removed from the wellbore (i.e., during pulling out). When the seal arrangement **650** reaches the desired position within the wellbore, it may be set against the casing **c** by energizing the motor **200** and pump **220** to circulate drilling mud downwardly through the axial mud passage **660**. When this occurs, hydraulic pressure is decreased within the annulus below the seal assembly **650** as compared to the pressure within the mud passage **660**, and the trip valve **680** is closed to fluid flow. As a result, borehole fluids are prevented from bypassing the seal assembly **650**. Annulus fluid pressure below the seal arrangement **650** will also be less than the annulus fluid pressure above the seal arrangement **650**. Pressurized fluid in the concavities **678** of the mud cups **668** then reinforces and sets the contacting portions **672** of the mud cups **668** against the casing **c** to set the seal arrangement **650** within the casing **c**.

[0063] Referring now to **Figures 9** and **10**, there is illustrated a further exemplary seal arrangement **700** that may serve as the annular seal assembly **299** for the APD device **170**. This embodiment of seal assembly is useful in situations wherein the drill string is run into a wellbore and utilized without rotating the drill string. An example of such a system is the VERTITRAK® system that is available commercially from Baker Hughes Incorporated. The seal arrangement **700** includes a housing **702** with an upper axial end **704**, lower axial end **706** and radially enlarged central portion **708** defined therebetween. The housing **702** defines an axial mud passage **710** therewithin. Two upper branch passages **712** extend from the axial

mud passage **710** through the housing **702** to interconnect the axial passage **710** with the radial exterior of the housing **702**. Two lower branch passages **714** also extend from the axial mud passage **710** through the housing **702** to interconnect the axial passage **710** with the radial exterior of the housing **702**.

[0064] A sleeve **716** surrounds the majority of the length of the enlarged central portion **708** of the housing **702** and is rotatably disposed thereupon. The sleeve **716** includes a mud seal section **718** and a valve closure section **720**. The mud seal section **718** includes a plurality of mud cups **668**, of the type described earlier. The valve closure section **718** includes a cylindrical wall having a pair of openings **722** (one shown) therein. Rotation of the sleeve **716** causes the openings **722** to be selectively aligned and unaligned with the lower branch passages **714** of the housing **702**, thereby selectively opening and closing the passages **714** to fluid flow therethrough.

[0065] Prior to running in of the seal arrangement **700**, the sleeve **716** is rotated upon the housing **702** to a first position wherein the openings **722** are aligned with the lower branch passages **714** and permit fluid to enter the branch passages **714** and thereby be transmitted from the radial exterior of the housing **702** to the axial passage **710**. During running in of the seal arrangement 700, the contacting portions **672** of the mud cups **668** contact the surrounding casing **c** and slide along it. Wellbore fluid contained within the casing **c** is able to bypass the seal arrangement **700** by flowing into the lower branch passages **714**, axial passage **710** and then radially outwardly through the upper branch passages **712**. When the seal arrangement **700** reaches the desired level within the wellbore, the drill string is rotated with respect to the casing **c**. Due to the engagement of the mud cups **668** with the surrounding casing **c**, the sleeve **716** is caused to rotate upon the outside of the central portion **708** of the housing

702, thereby closing the lower branch passages **714** to fluid flow. In order to then set the seal arrangement **700** within the wellbore, drilling mud is circulated down through the axial passage **710** by operation of the motor **200** and pump **220**. As noted, previously, this decreases the fluid pressure within the annulus below the seal assembly **700** as compared to the annulus fluid pressure above the seal arrangement **700**. The mud cups **668** become set against the casing **c** in the same manner as described previously with respect to seal arrangement **650**.

[0066] **Figures 11** and **12** illustrate a further alternative embodiment for a seal assembly **299** which is embodied as seal arrangement **750**. The seal arrangement **750** features a housing **752** with upper and lower axial ends **754**, **756** and a cylindrical central portion **758**. The central portion **758** carries thereupon an radially-expandable annular seal element **760**. The seal element **760** is moveable between two positions: a first position (seen in **Figure 11**) in which the seal element **760** is radially retracted, and a second position in which the seal element **760** is radially expanded. In a preferred embodiment, the seal element **760** includes a sealing portion **762**, such as an elastomeric membrane that is capable of seating against the casing **c** to create a fluid seal. In addition, the seal element **760** includes a spring portion **764**, which biases the sealing portion **762** toward the second, radially outward position. The spring portion **764** may comprise a mechanical spring member or series of spring members arranged circumferentially about the housing **752**, or a fluid spring arrangement that is capable of biasing the sealing portion **762** radially outwardly.

[0067] The seal arrangement **750** also features a sliding sleeve actuation system for selectively actuating the seal element **760** for engagement with the casing **c**. An annular sleeve **764** surrounds the central portion **708** of the housing **752** and is axially slidable thereupon between two positions. In the first position, shown in **Figure 11**, the

sleeve **764** surrounds the seal element **760** and retains it in the retracted position. In the second position, depicted in **Figure 12**, the sleeve **764** is moved axially upon the housing **752** until it not longer restrains the seal element **760** to its retracted position. The sliding sleeve **764** may be actuated for movement between its two positions through use of a wireline engagement tool, a motor actuator, or by other means known in the art.

[0068] In operation, the seal arrangement **750** is run into the wellbore with the sleeve **764** in its first position, as shown in **Figure 11**, so that the seal element **760** is restrained to its radially retracted position. When the seal arrangement **750** is disposed at the depth in which it is desired to set the seal arrangement **750**, the sleeve **764** is actuated to move from its first position to its second position, thereby allowing the seal element **760** to move to its second, radially expanded position and seal against the casing **c**. If it is desired to unseat the seal arrangement **750**, the sleeve **764** is actuated to be returned to its first position, thereby again restraining the seal element **760** in its retracted position.

[0069] While the foregoing disclosure is directed to the preferred embodiments of the invention, various modifications will be apparent to those skilled in the art. It is intended that all variations within the scope and spirit of the appended claims be embraced by the foregoing disclosure.